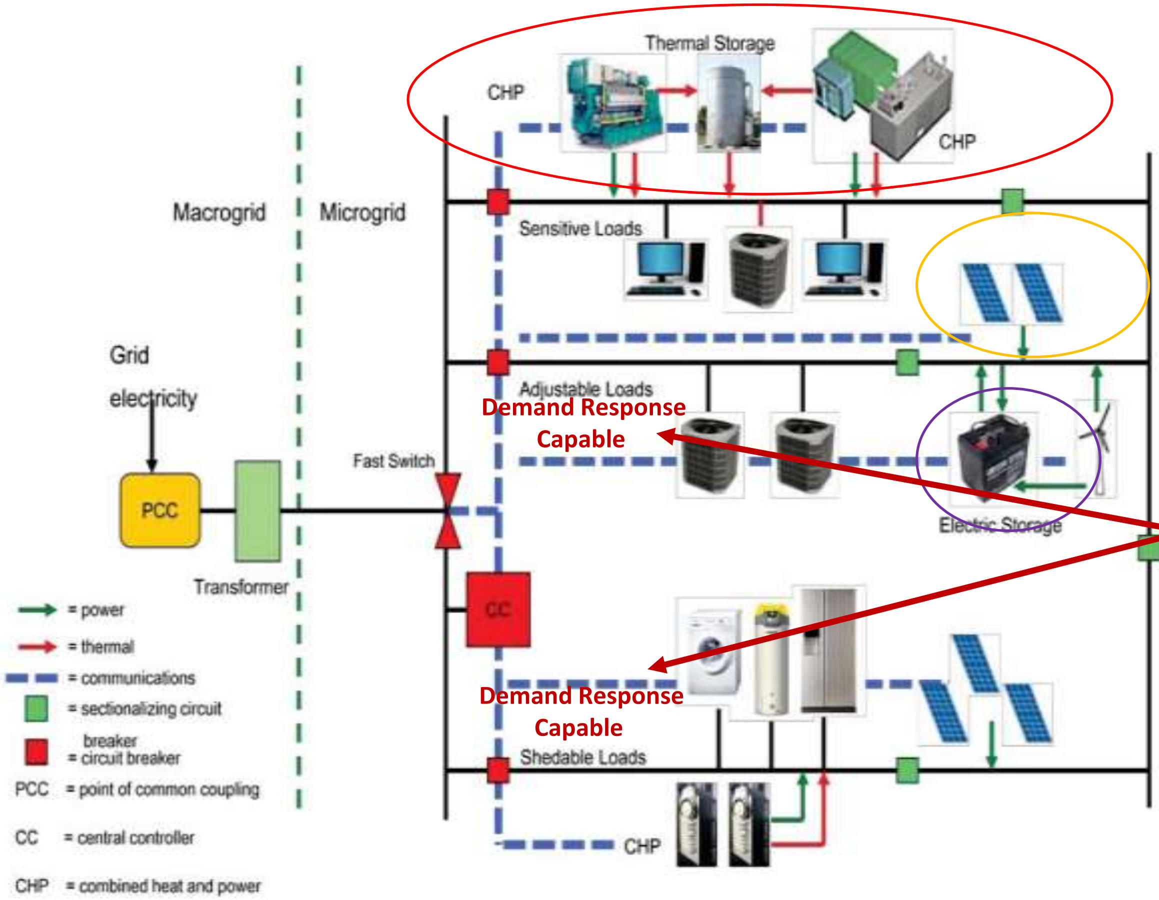
Promoting CHP & CHP Enabled DG/ Renewable Energy Microgrids in PA

Inserting On-Site Energy (Electric, Thermal) into Municipal, Rural T&D Systems



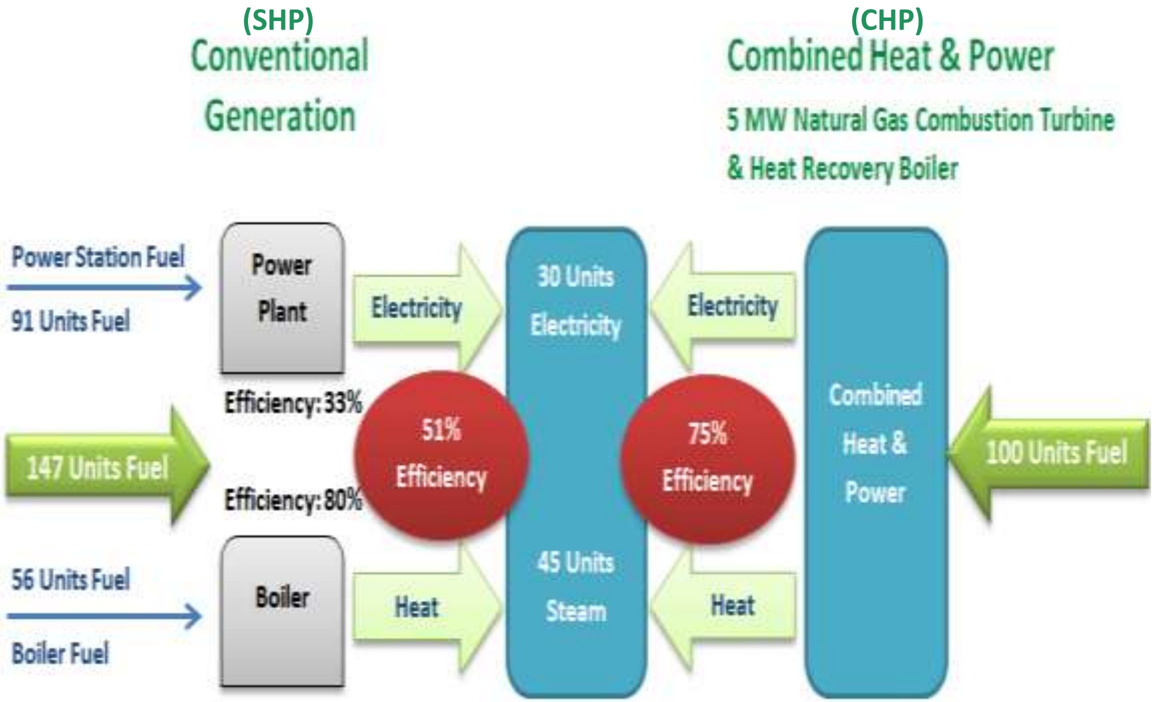
- Importance of knowing envelope load response to local environment and occupant activity variance

Combined Heat & Power (CHP) vs Separate Heat & Power (SHP)

The process for evaluating the potential for new CHP begins with identifying facilities or sites that possess the energy load characteristics and requirements that are technically conducive for CHP applications.

The Opportunity for CHP in the United States (May 2013, **Prepared for:** American Gas Association ,Washington, DC by ICF)

$$PEUF_{SHP} = \frac{Q_D + W_{eD}}{PF_{GTD} + PF_B} = \frac{30 + 45}{147} = 0.51$$



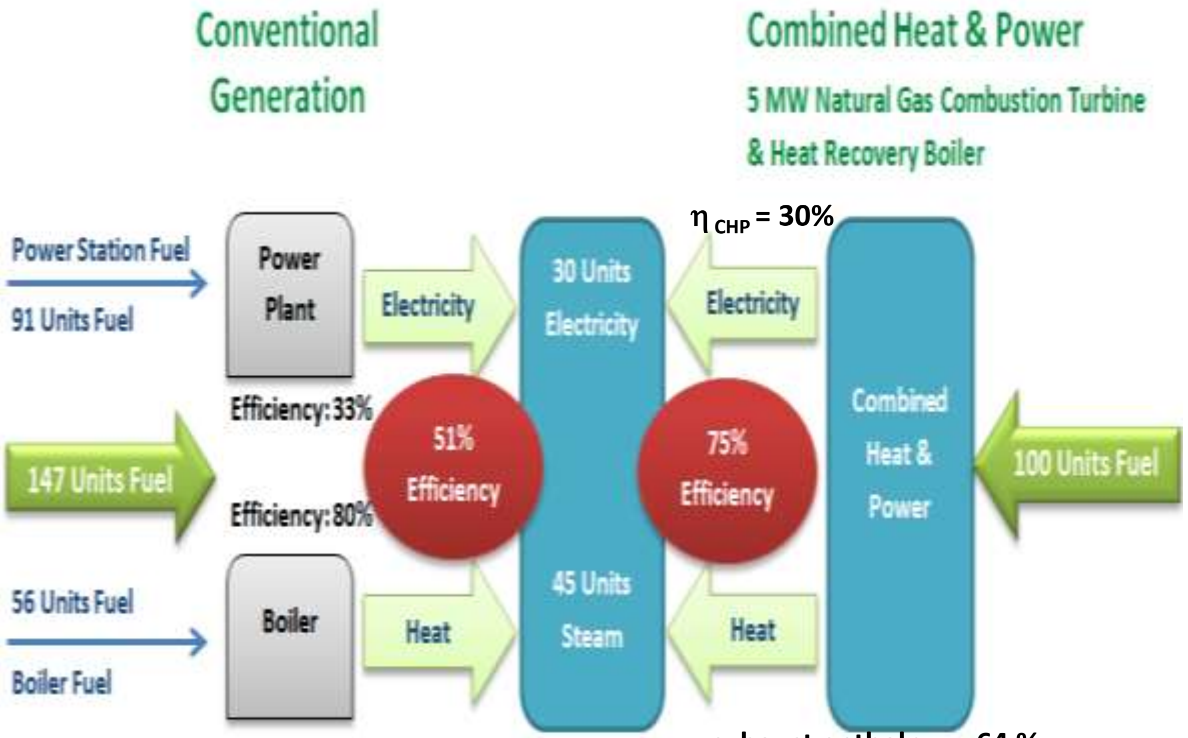
$$PEUF_{CHP} = \frac{Q_D + W_{eD}}{PF_{CHP}} = \frac{30 + 45}{100} = 0.75$$

Q_D = 45 Units
W_{eD} = 30 Units

$$\lambda_D = \frac{Q_D}{W_{eD}} = 1.5$$

Combined Heat & Power (CHP) vs Separate Heat & Power (SHP)

The *Combined* Subsystems More *Primary Fuel Efficient* Than Separate Subsystems



$\eta_{HRU,}$ exhaust enthalpy = 64 %

$\eta_{HRU,}$ primary fuel= 45 %

Q_D = 45 Units

W_{eD} = 30 Units

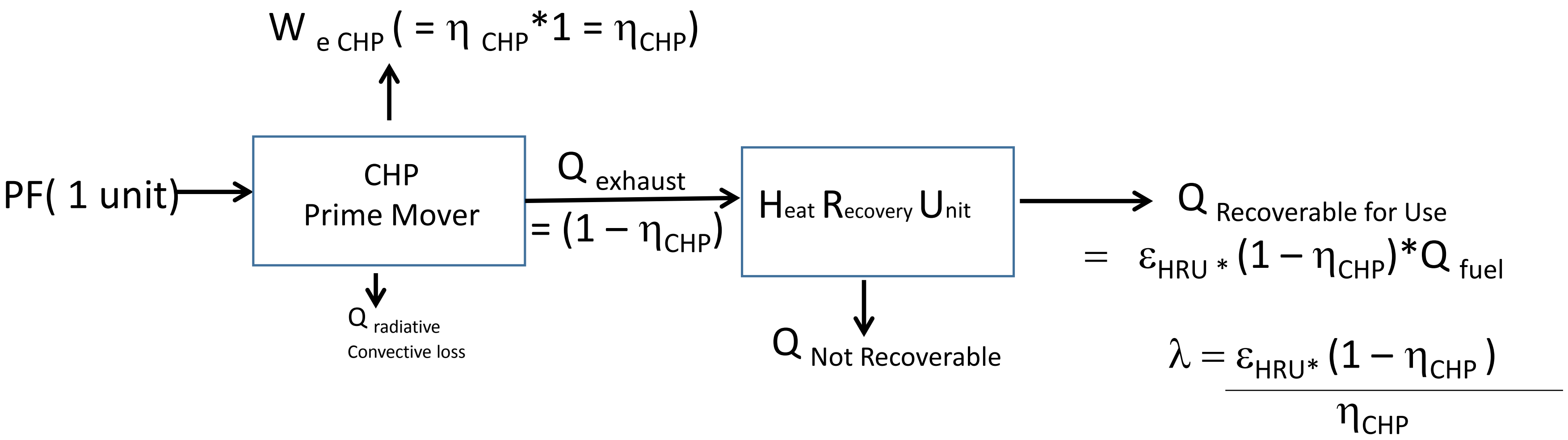
$\lambda_D = \frac{Q_D}{W_{eD}} = 1.5$

$\eta_{eCHP} \leq \eta_{eGTD}$

$\eta_{Q\,HRU\,CHP} < \eta_{Q\,fuel\,Boiler}$

But: $\eta_{CHP\ System} > \eta_{SHP\ \text{“System”}}$

CHP Performance Design Considerations
Design to Thermal Demand



$$\lambda_{CHP} = \frac{Q_{CHP}}{W_{e\,CHP}} = \frac{\varepsilon_{HRU*}(1-\eta_{CHP})}{\eta_{CHP}}$$

If $\eta_{CHP} = 0.30$ and $\boldsymbol{\varepsilon_{HRU} = 0.70}$**, then** $\boldsymbol{\lambda_{CHP} = 1.63}$

How "well" (i.e. Load factor (time, amount) does λ_{CHP} match λ_D?

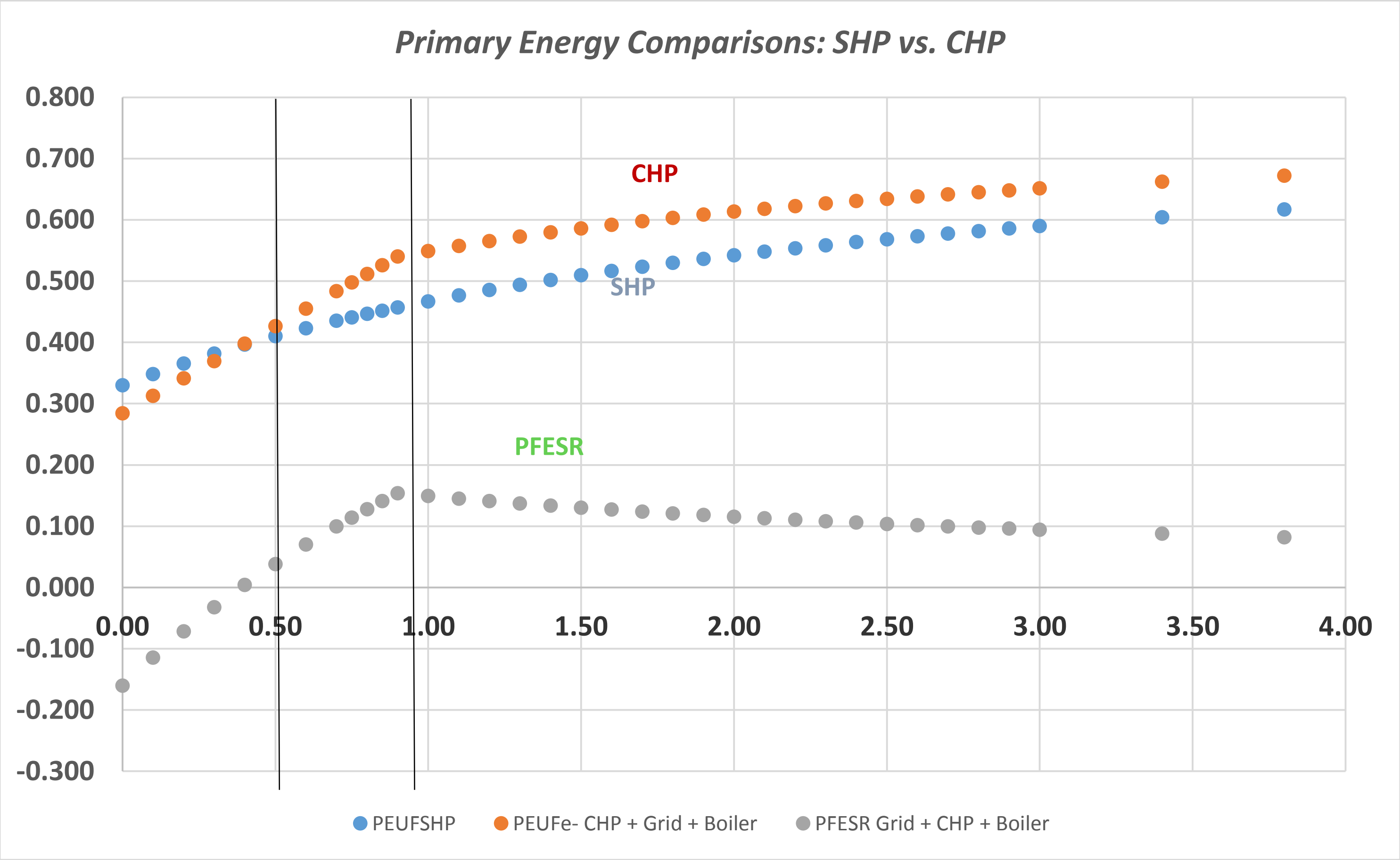
What is the λ_{CHP} load factor for the CHP system at the site?

and

$$W_{e\,CHP} \overset{?}{\leq} W_{e\,D}$$

CHP with GTD and Supplemental Boiler

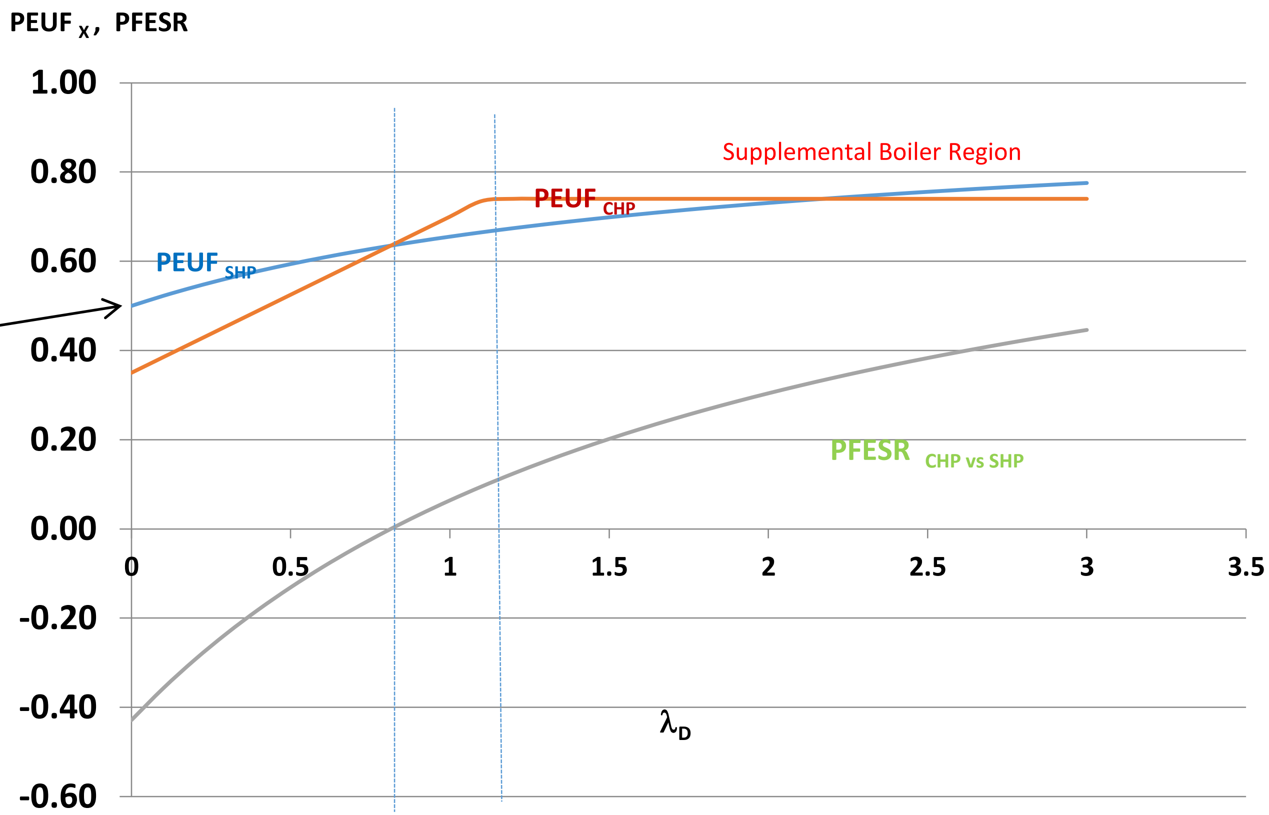
η_{GTD}	0.33
η_{B}	0.80
η_{CHP}	0.25
$e_{recoverable\ q\ CHP}$	0.60
$I_{recoverable\ CHP}$	1.80
$I_{Not\ Recoverable\ CHP}$	1.20
$W\ e\text{-}_{D}$	1.00
$F_{1\ unit}\ e\text{-}_{CHP}$	4.00
$\text{Quality}_{I\ avail\ CHP}$	
$W\ e\text{-}_{D}$	1.00
$f_{e,D}^{CHP}$	0.50
$f_{e,D}^{GTD}$	0.50
$I'_{D,CHP}$	0.9



Combined Heat & Power (CHP) vs Separate Heat & Power (SHP) – Generalizing the Analysis
Effect of a Greening GTD System – λ_D Window Narrows

η_{GTD}	0.50
η_{B}	0.95
η_{CHP}	0.35
$\eta_{recoverable\ q\ CHP}$	0.60
$\lambda_{recoverable\ CHP}$	1.11
$\lambda_{Not\ Recoverable\ CHP}$	0.74
$W_{\varepsilon-CHP}$	1.00
$F_{1\ unit\ \varepsilon-CHP}$	2.86

Combined Cycle
Gas + Steam Turbine
Central Generating



As the central GTD system becomes more efficient / carbon free and condensing boilers/furnaces more prevalent, the competitive CHP λ_D window narrows.

But Hybrid CHP in the form of distributed micro-grids and district energy systems will enable the greening of the GTD as well as increased resiliency.

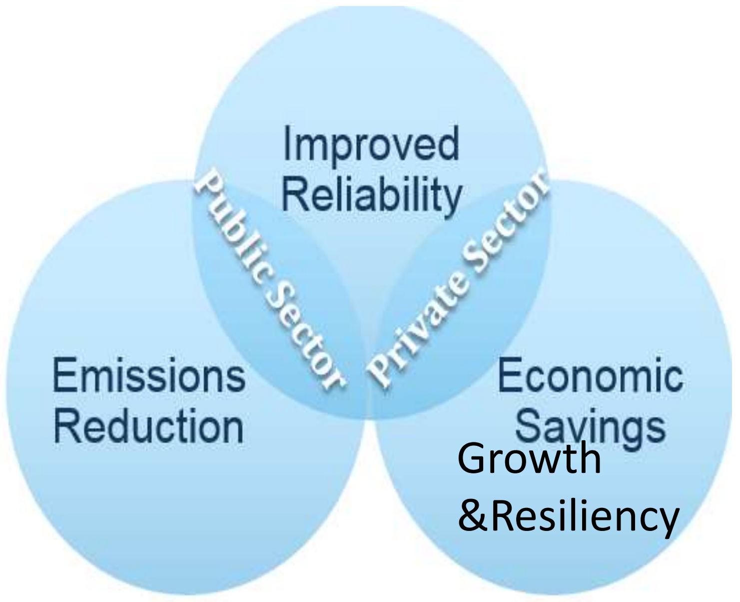
What Are the Benefits of CHP with Hybrized Renewables ?

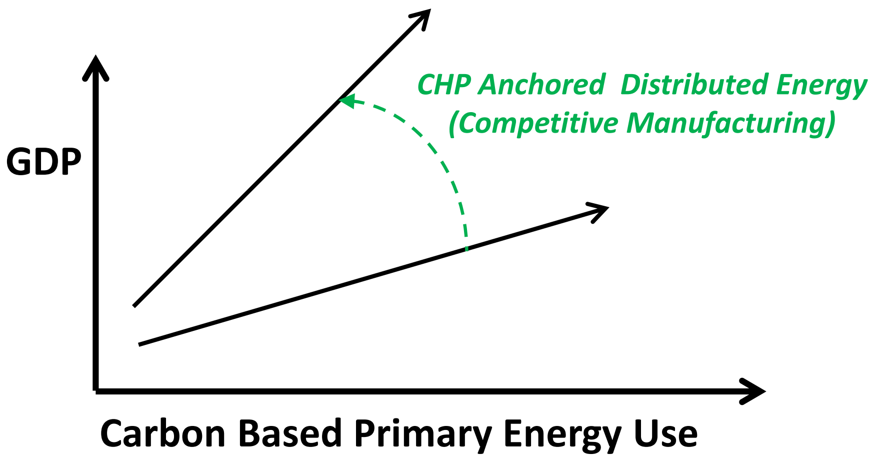
- CHP is more primary energy efficient than separate generation of electricity and heating/cooling, provided relatively constant coincidental electric and thermal demand
- Higher efficiency translates to lower operating costs (but requires upfront capital investment)
- Higher efficiency reduces emissions of pollutants, particularly with respect to coal fired central plants
- CHP can also increase energy reliability/resiliency and enhance power quality in specific applications
- *Hybridized with renewables, CHP systems can enable economically feasible path to net zero carbon operation*

Distributed Energy Innovation Partnership

A Living Laboratory: The Philadelphia Navy Yard PIDC Grid and Building 7R

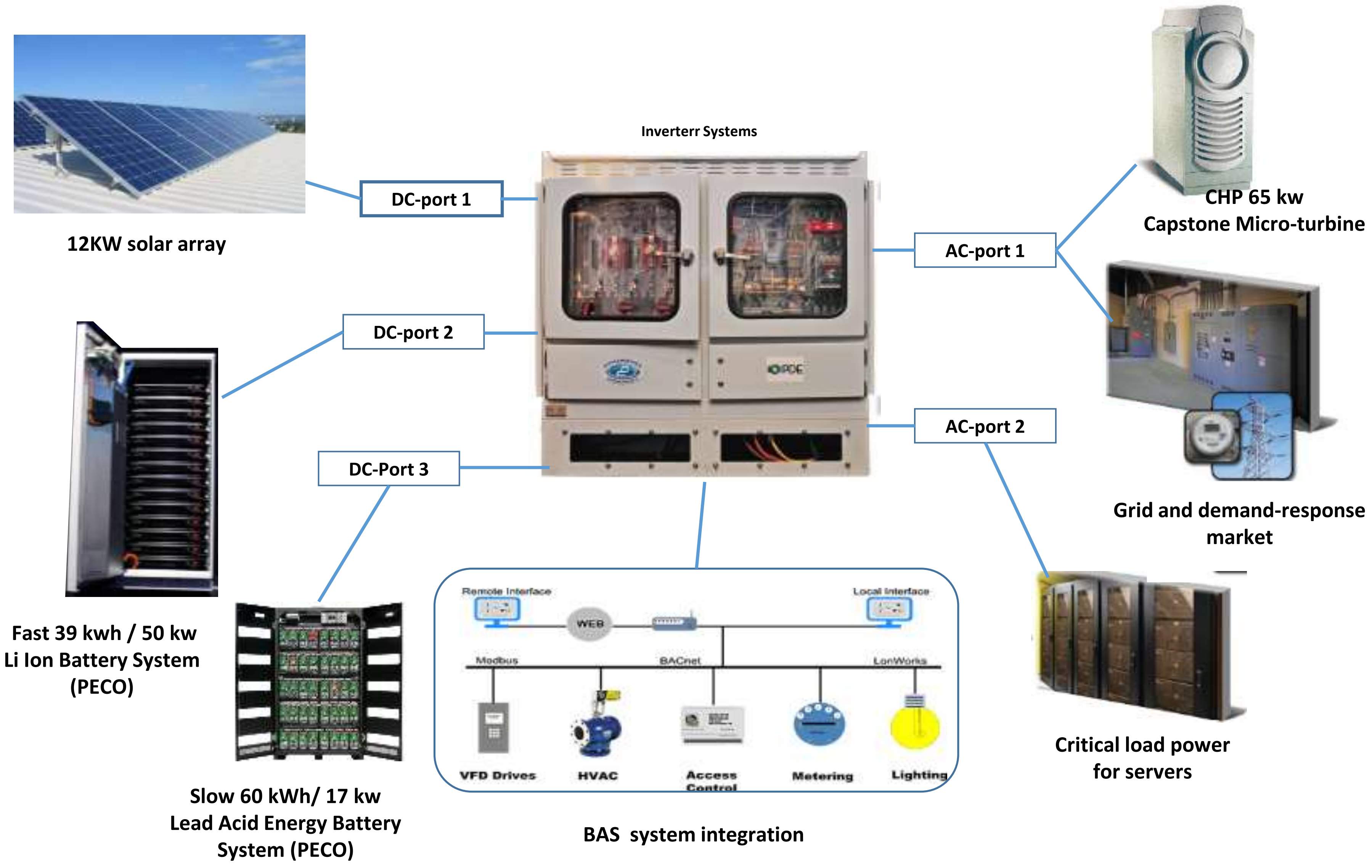
Headquartered at the Philadelphia Navy Yard, DEIP serves as a nexus for collaboration and exchange for regional, national and global applications of distributed energy systems. DEIP leverages interdisciplinary expertise to advance research in critical topics and to grow capacity of students and professionals as leaders in distributed energy industry.



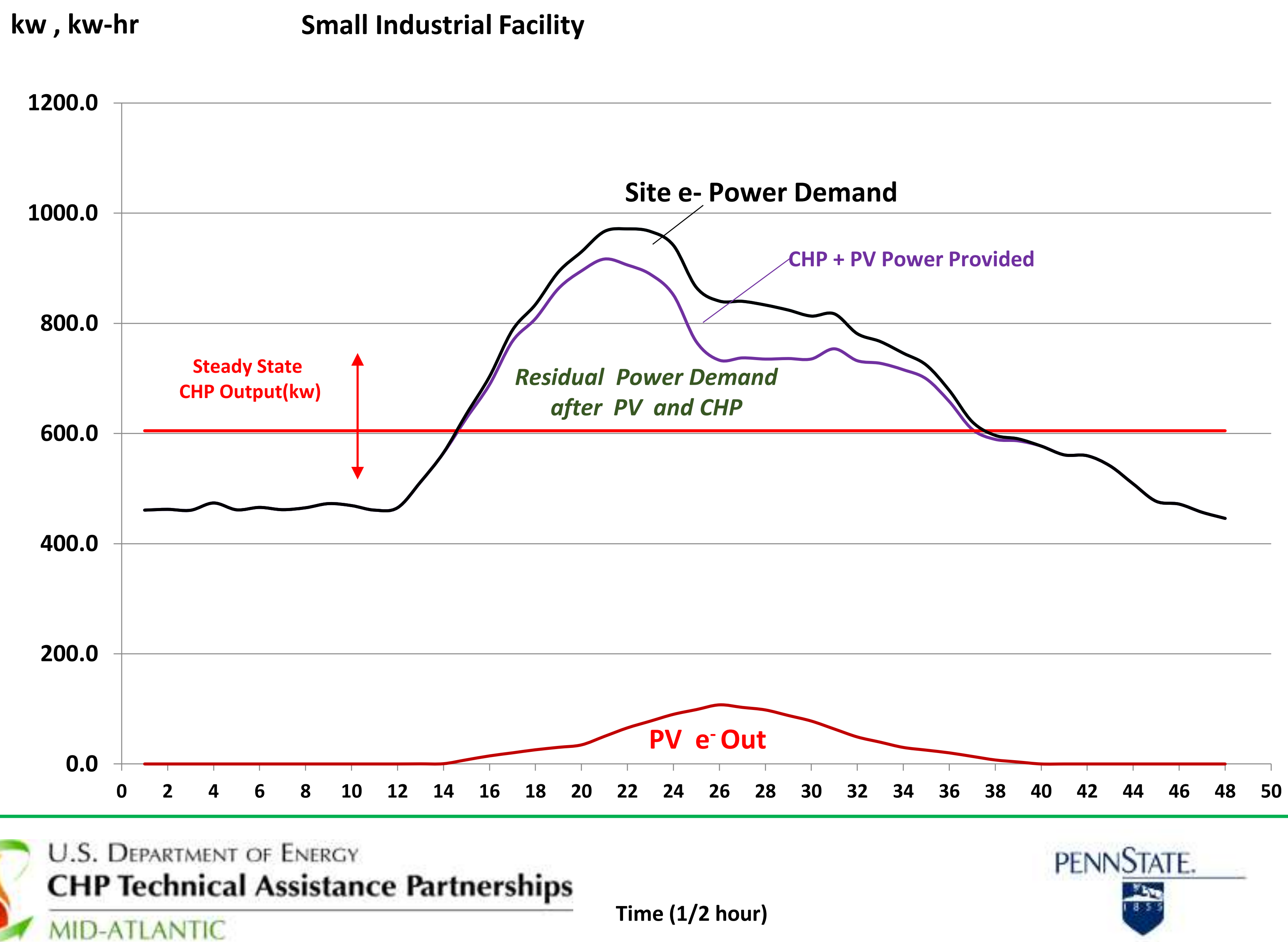


PSU Navy Yard Building 7R

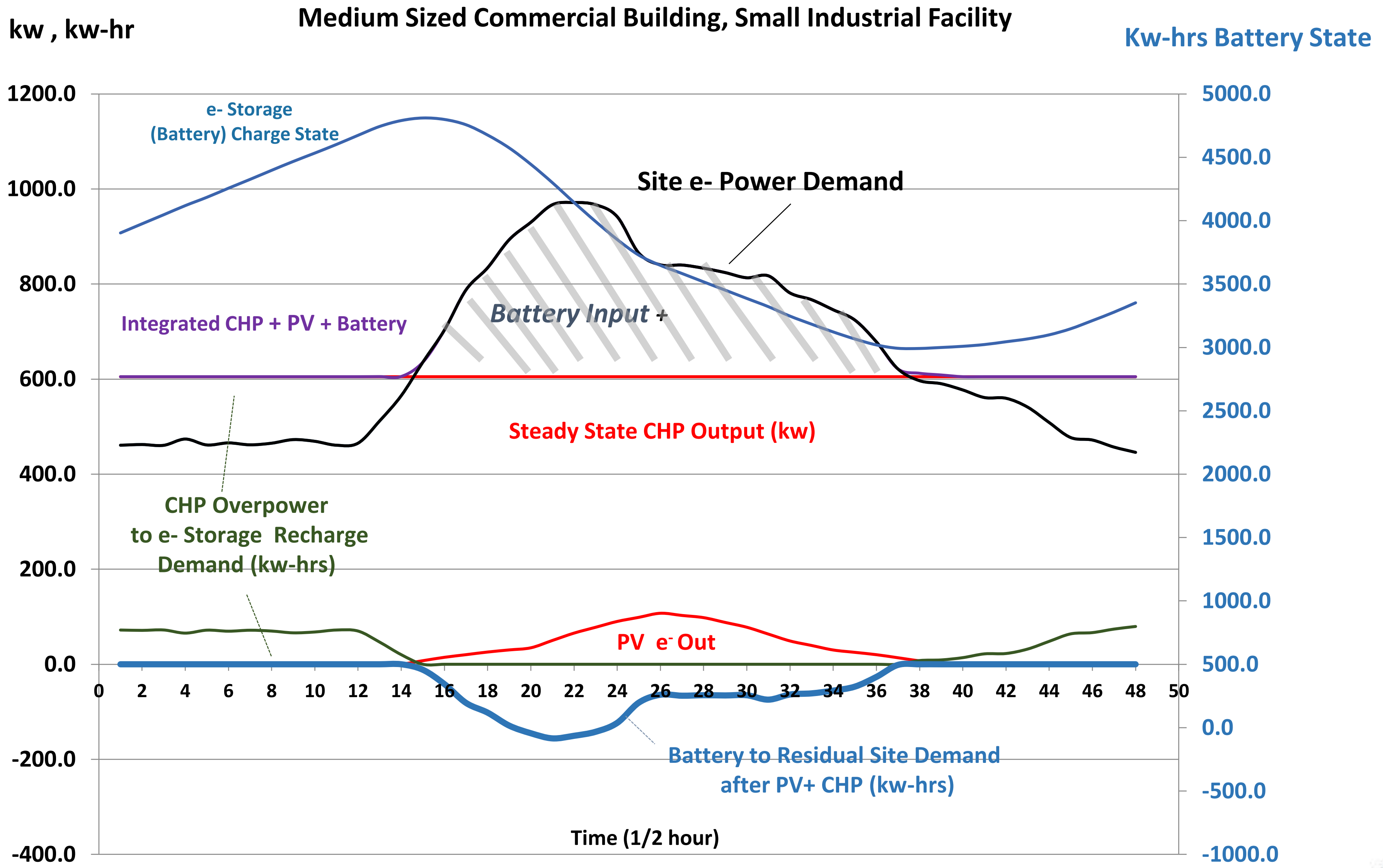
PA DEP Building 7R CHP Enabled Renewables



CHP with PV Renewables for Distributed Energy



CHP + PV Renewables + Storage (HYBRID System) to Meet Demand Curve



U.S. Department of Energy
CHP Technical Assistance Partnerships
MID-ATLANTIC

PENNSTATE

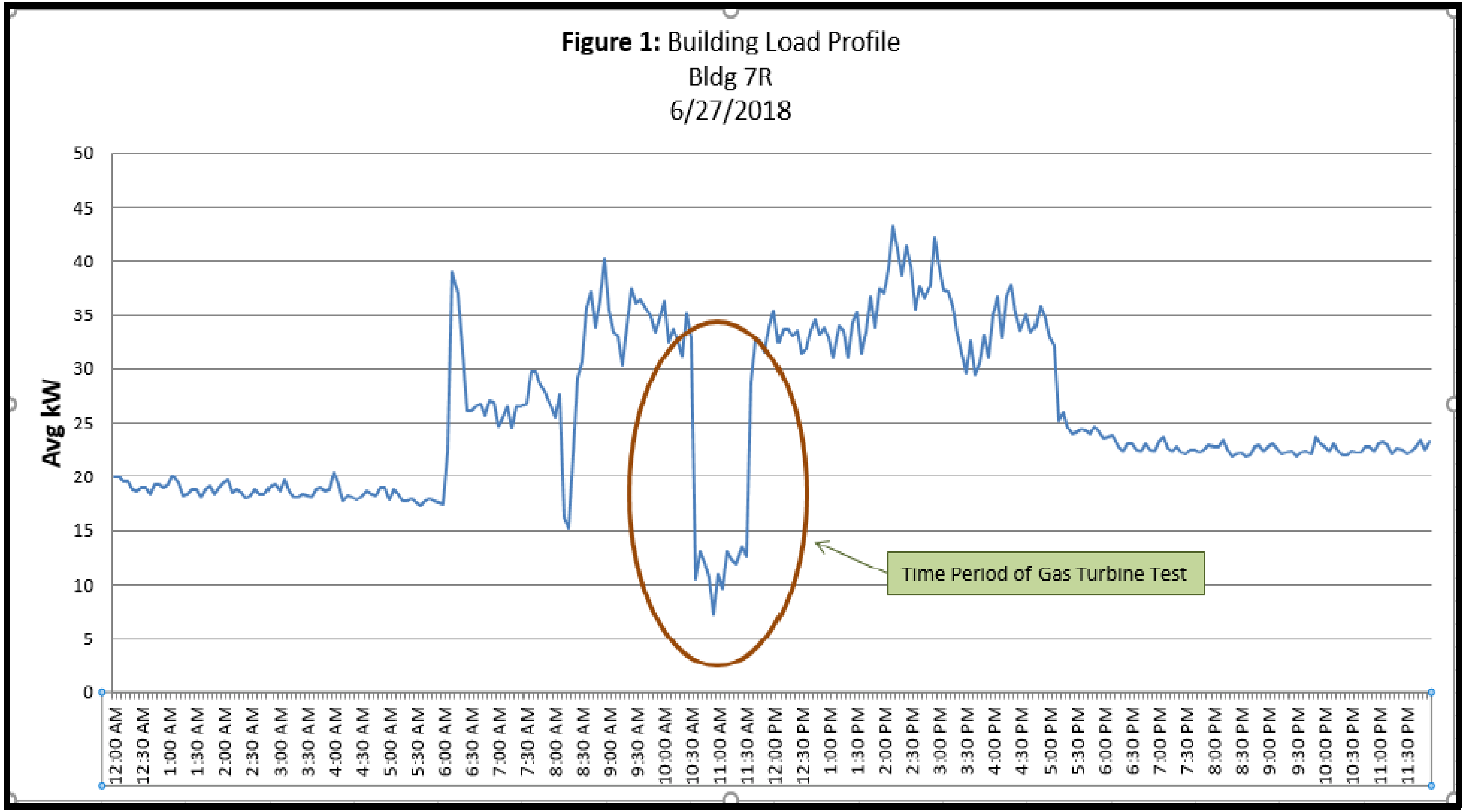


Figure 1: Building Load Profile
Bldg 7R
6/27/2018
Avg kW
50
45
40
35
30
25
20
15
10
5
0
Time Period of Gas Turbine Test
12:00 AM
12:30 AM
1:00 AM
1:30 AM
2:00 AM
2:30 AM
3:00 AM
3:30 AM
4:00 AM
4:30 AM
5:00 AM
5:30 AM
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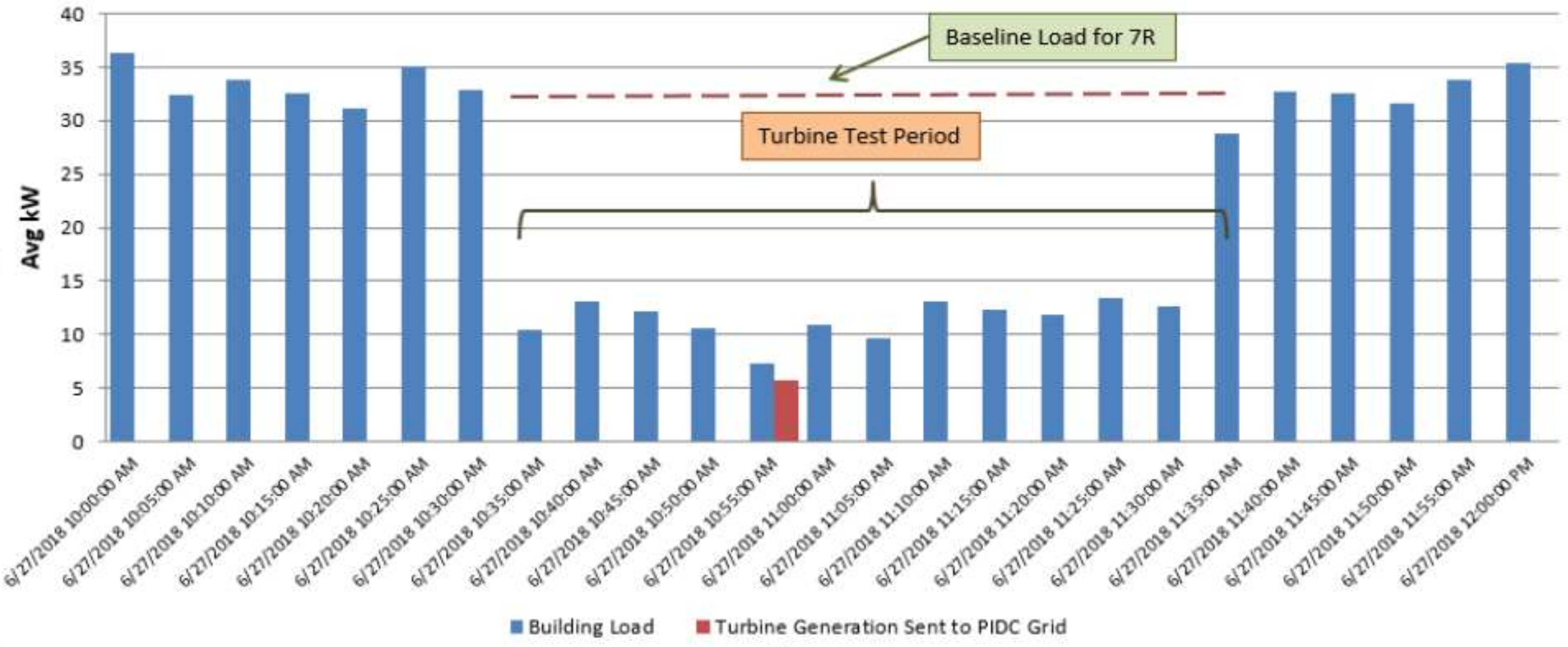
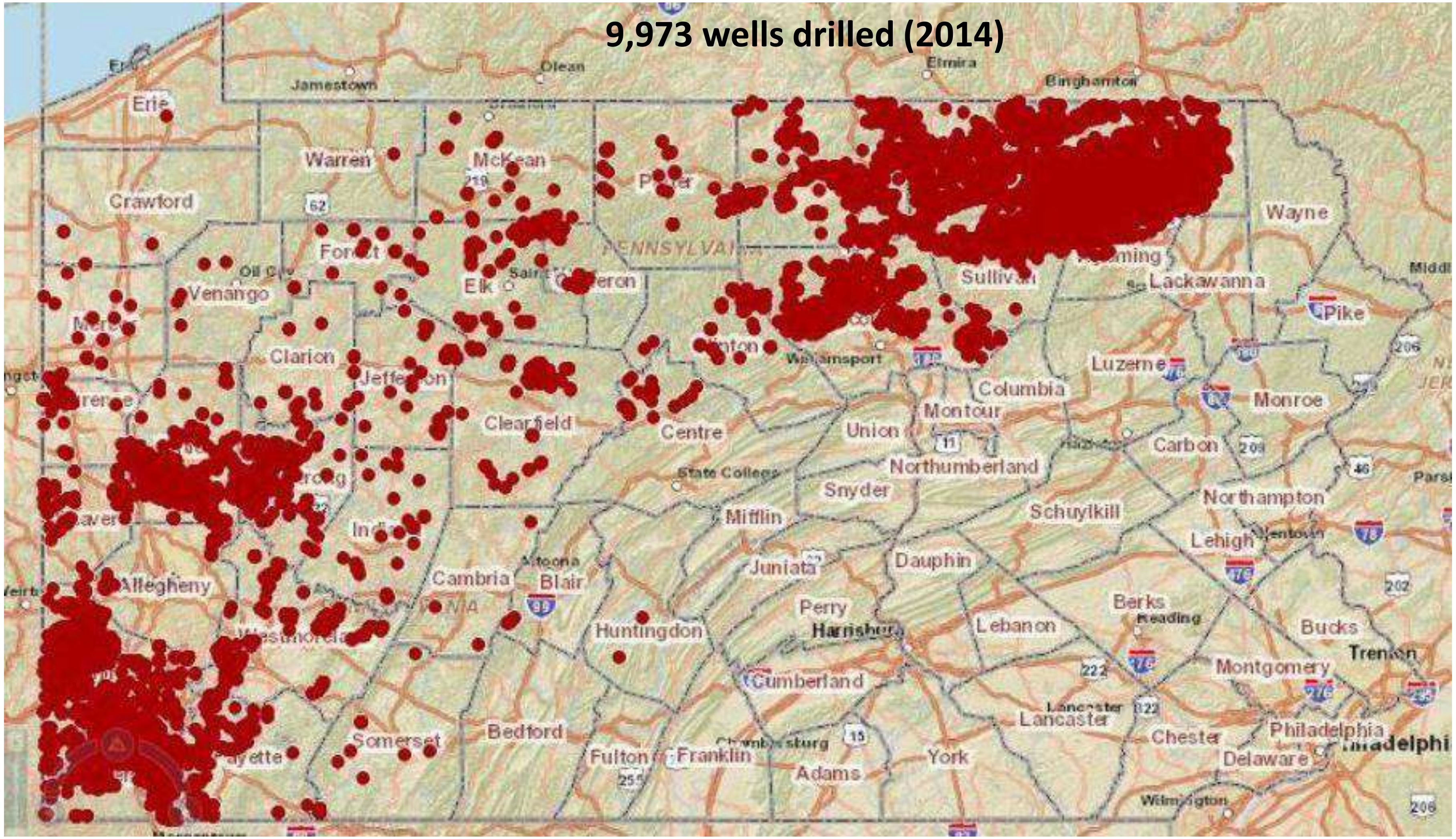
Figure 2: Building Load and Gas-Turbine Generation to PIDC Grid
Bldg 7R - DTE Interval Meter Data
10:00am to 12:00pm 6/27/2018



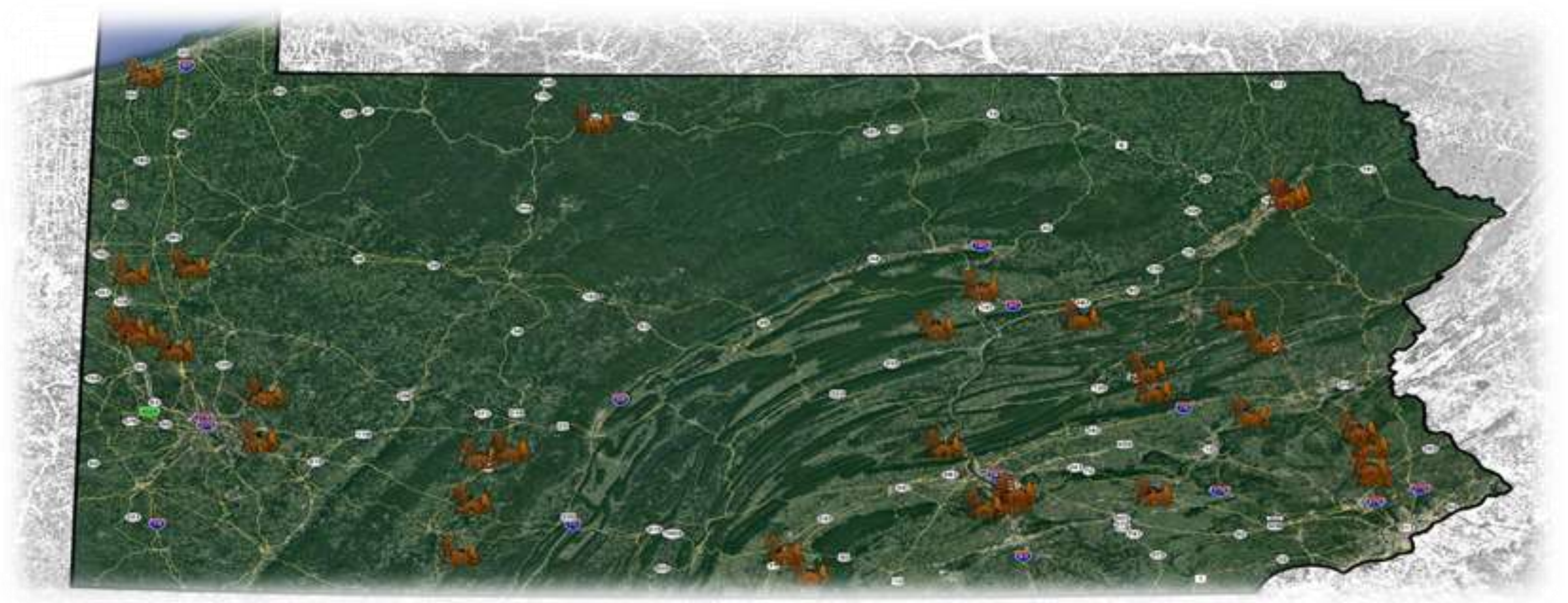
MARCELLUS SHALE EXPLORATION & PRODUCTION

pennsylvania
DEPARTMENT OF COMMUNITY & ECONOMIC DEVELOPMENT



A Distributed Energy Innovation Partnership Focus Area:
Transformation of Municipal and Rural Cooperative Electric Grids to Renewable Energy Microgrids

35 municipalities and 13 rural electric cooperatives provide power to customers, but are not under Pennsylvania PUC jurisdiction



There are 900 rural electric cooperatives in the U.S. in 47 states that provide electric service to 56% of the nation's landmass. And across the U.S. there are 2000 public power utilities (Municipal Grids) that provide electricity to 49 million people in 49 states.

Benefits of Distribution Level Generation in PJM

Transmission Cost Offsets

- As network transmission rates continue to rise, peak-shaving can reduce the peak billing determinants for the following year
- Because the transmission peaks are based on only **1 hour** occurring in either Winter or Summer, distributed resources must be reliable throughout the year to provide this benefit repeatedly

Capacity Cost Offsets

- Distributed generation can be used to peak-shave the capacity billing units for the following year
- Because the capacity peaks are based on **5 hours**, all occurring during Summer, distributed resources do not have to be versatile in the ability to provide benefits in both peak seasons

Congestion Cost Offsets

- Distributed generation is already delivered behind the substation meter, so there is no potential to incur hefty congestion premiums as there would be with hedges with various delivery locations

Other Benefits

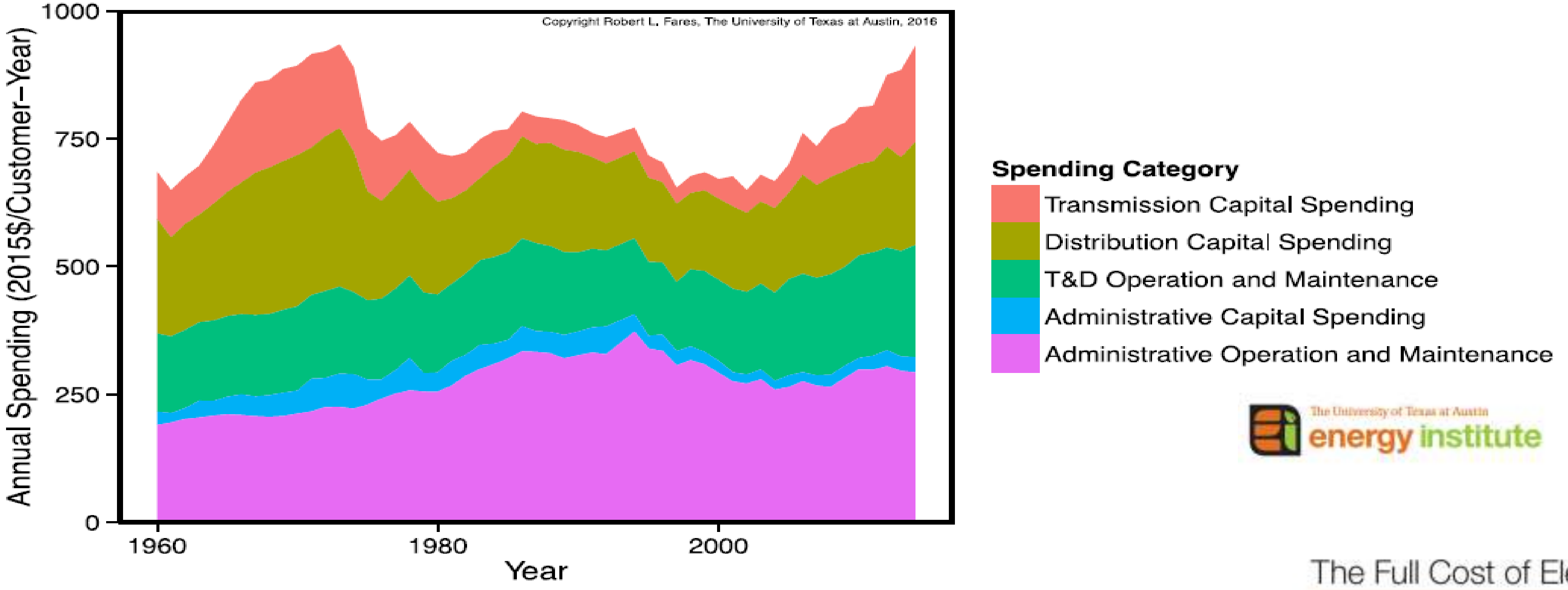
- Distributed generation avoids PJM admin and ancillary service fees
- Distributed generation provides ample opportunity for a municipal to invest in green initiatives and is local, both points which can provide social benefits in the form of positive publicity and customer approval

Transmission and Distribution Costs of GTD System

TABLE 2

This table summarizes the correlation between total annual transmission, distribution, and administration costs, and the number of customers in a utility's territory, annual peak demand, and annual energy sales (using FERC Form 1 data from 1994 to 2014). The value of the cost coefficient and the corresponding R^2 value are given for each regression analysis performed.

Cost Category	Cost Per Customer (2015$/Customer-Year)	Cost Per Peak KW (2015$/kW-Year)	Cost Per kWh (2015¢/kWh)
Transmission	119 ($R^2 = 0.459$)	21 ($R^2 = 0.399$)	0.47 ($R^2 = 0.373$)
Distribution	291 ($R^2 = 0.901$)	52 ($R^2 = 0.775$)	1.1 ($R^2 = 0.740$)
Administration	333 ($R^2 = 0.853$)	61 ($R^2 = 0.766$)	1.3 ($R^2 = 0.734$)
Total	727 ($R^2 = 0.886$)	134 ($R^2 = 0.781$)	2.9 ($R^2 = 0.747$)



The University of Texas at Austin energy institute

The Full Cost of Electricity (FCe-)

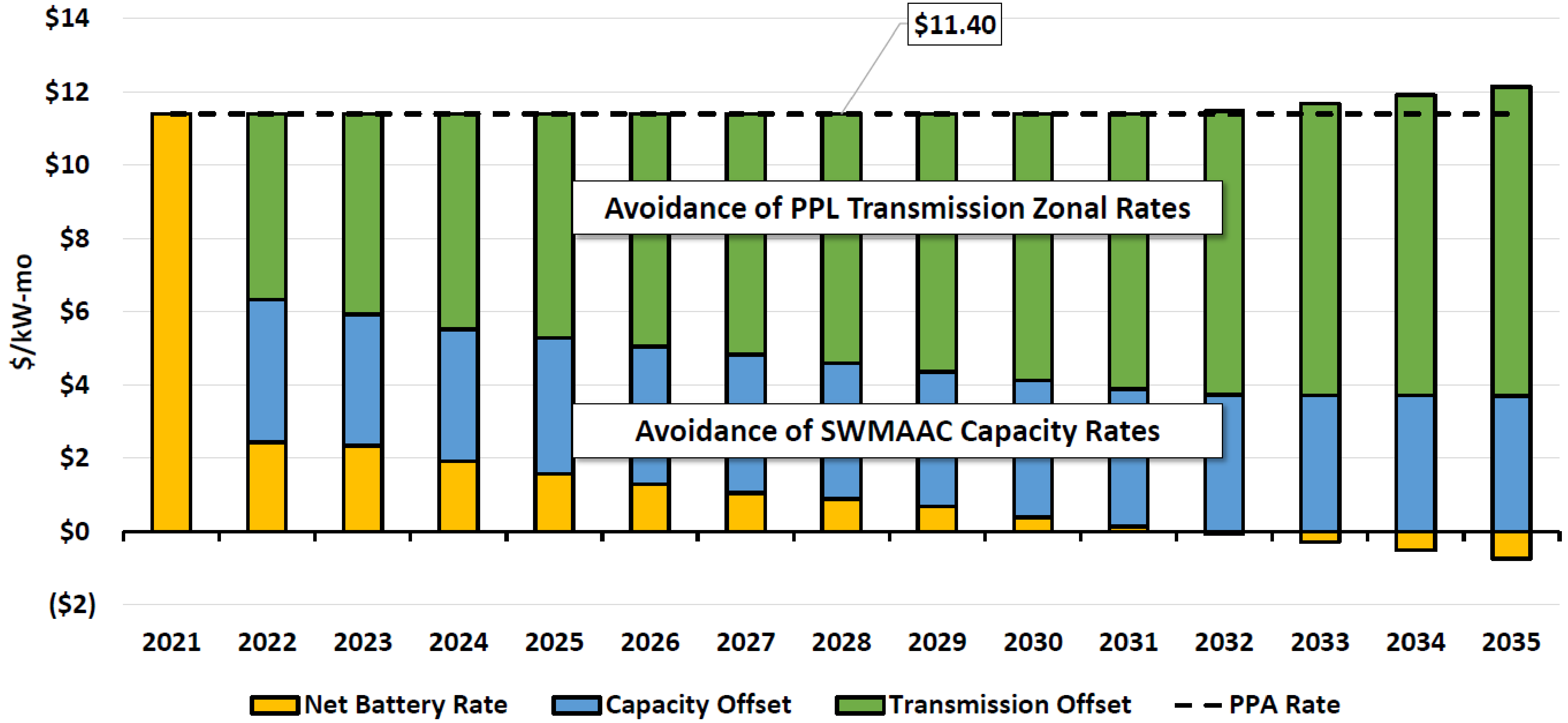
Annual Transmission Revenue Requirements and Rates		
Transmission Owner (Transmission Zone)	**Annual Transmission Revenue Requirement**	**Network Integration Transmission Service Rate ($/MW-Year)**
AE (AECO)	$136,632,319	$53,775
AEP (AEP)	$1,499,032,942	$65,923.43
AP (APS)	$128,000,000	$17,895
ATSI (ATSI, AMPT)	$707,792,792	$55,185.23
BC (BGE)	$230,595,535	$35,762
ComEd, Rochelle (CE)	$702,431,433	$34,515.60
Dayton (DAY)	$37,885,386	$12,561.48
Duke (DEOK)	$121,250,903	$24,077
Duquesne (DLCO)	$139,341,808	$51,954.44
Dominion (DOM)	$1,007,914,000	$47,471.44
Dominion Underground (DOM)	$34,420,176	$1,728.93
DPL, ODEC (DPL)	$163,224,128	$42,812
East Kentucky Power Cooperative (EKPC)	$83,267,903	$24,441
MAIT (METED, PENELEC)	$173,323,326	$28,796.22
JCPL	$135,000,000	$22,588.47
OVEC	$11,256,927	$5,163.73
PE (PECO)	$155,439,100	$19,093
PPL, AECoop, UGI (PPL)	$435,349,329	$58,865
PEPCO, SMECO (PEPCO)	$190,876,083	$31,166.72
PS (PSEG)	$1,194,757,707	$119,735.80
Rockland (RECO)	$16,833,707	$42,548
TrAILCo	$226,652,117.80	n/a
Transource West Virginia*	$7,352,030	n/a

* Effective April 30, 2019

Additional bulk transmission investments required to integrate new generation vary from $0–$600/kW of generation capacity, depending on where it is installed. All data based on analysis of transmission investment trends in the Electric Reliability Council of Texas (ERCOT) region [8].

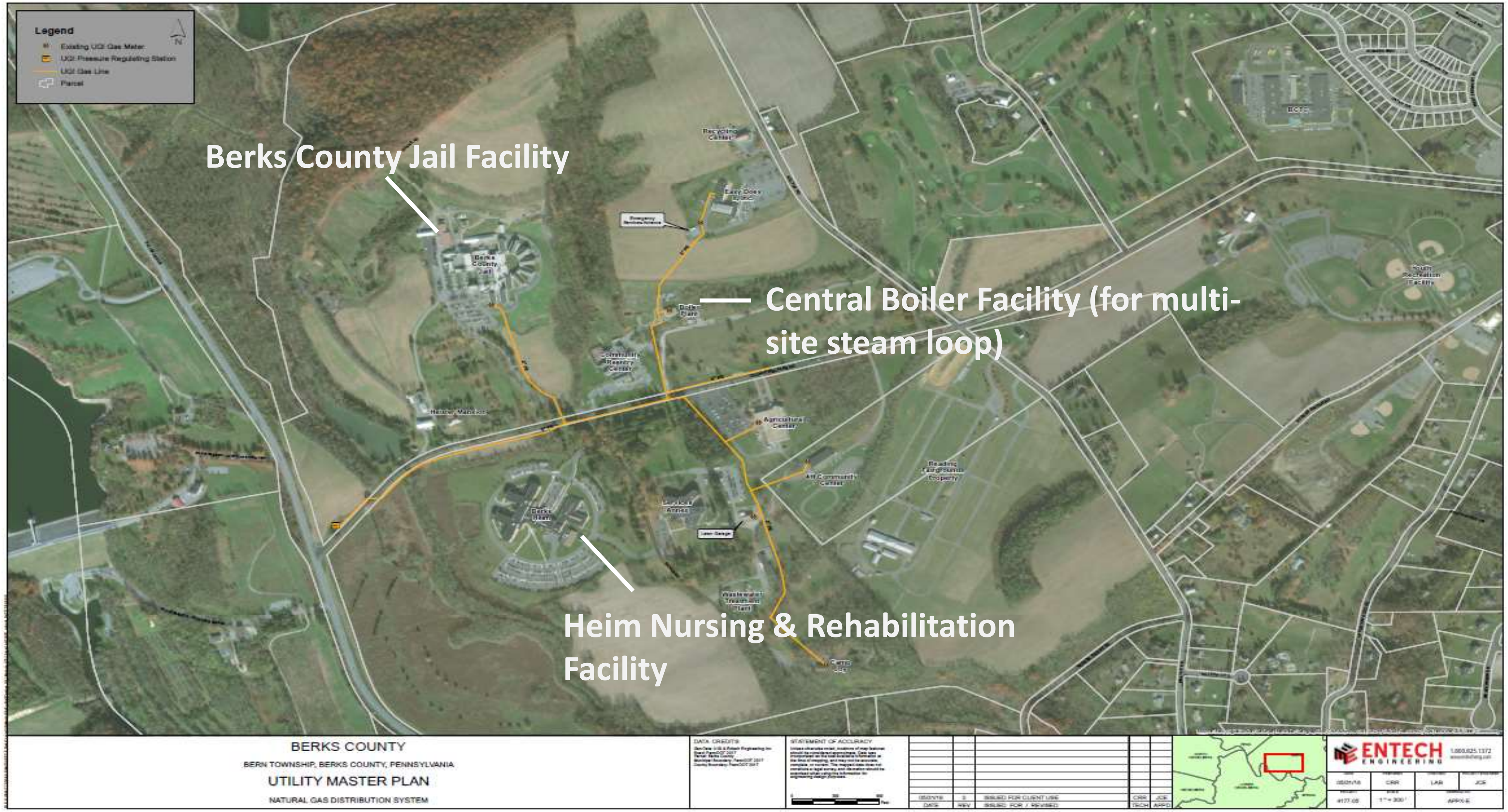
New generation project type	Bulk transmission upgrade cost by line voltage ($/kW)		
	345 kV	138 kV	69 kV
Greenfield – long-distance renewable energy transmission projects (using example of Texas CREZ project)	600	0	0
Greenfield – conventional projects	78	166	49
Brownfield projects	0	0	0

Battery Storage Feasibility
3 MW, 2 Hour Duration



A Distributed Energy Innovation Partnership Focus Area:

Transformation of Municipal and Rural Cooperative Electric Grids to Renewable Energy Microgrids



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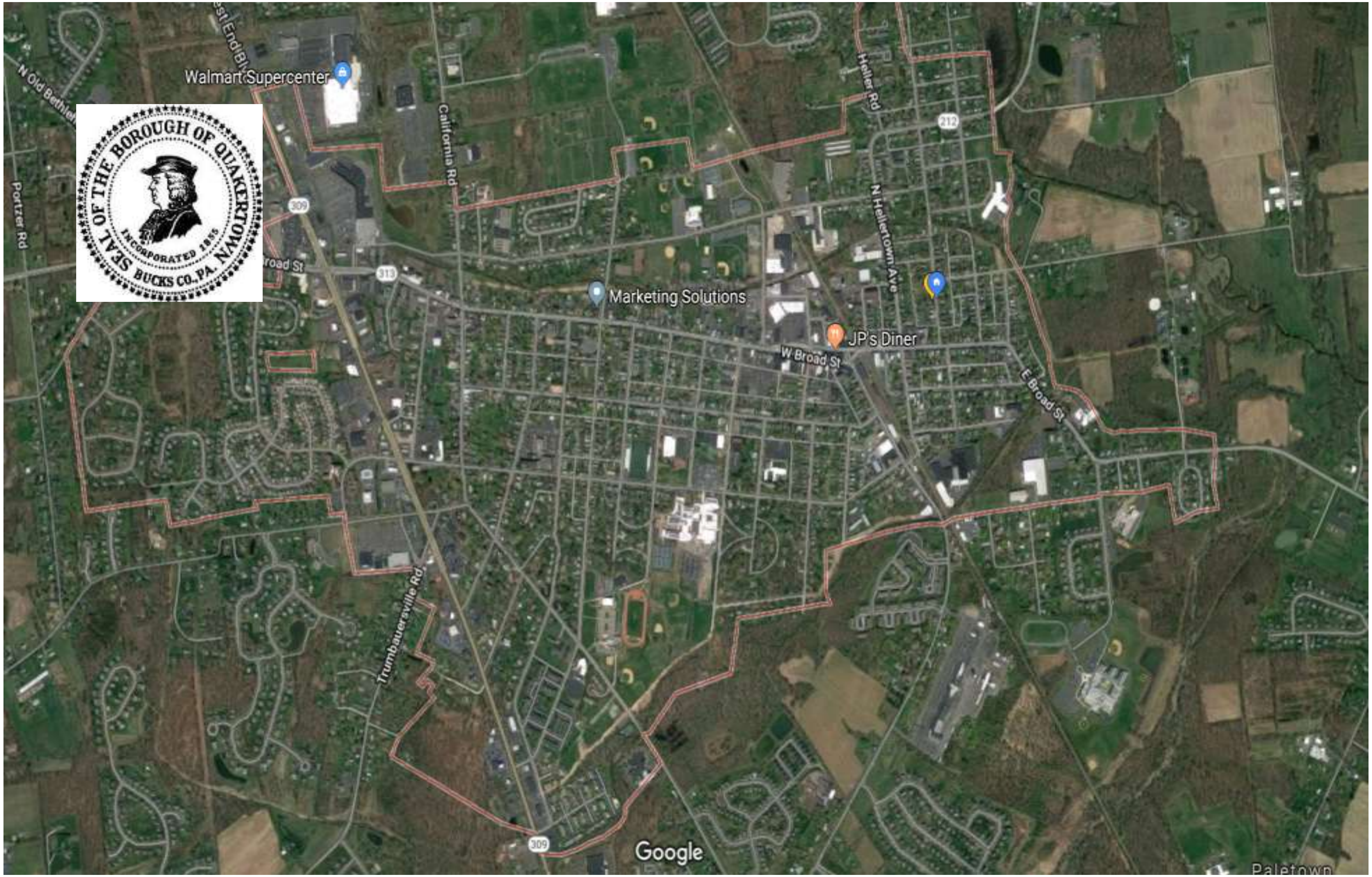
PennState
at The Navy Yard

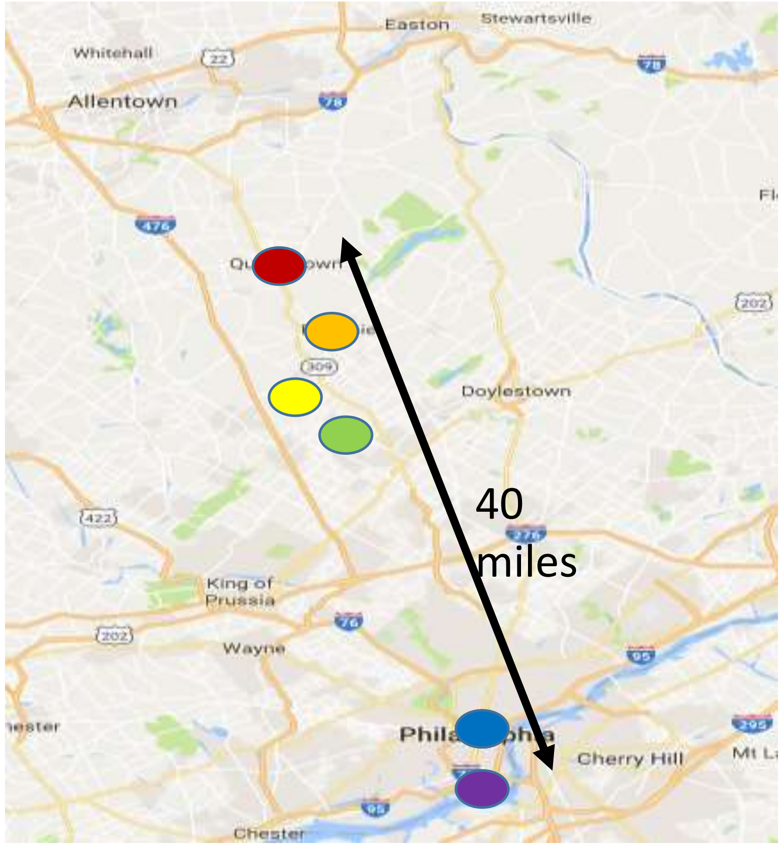
A Distributed Energy Innovation Partnership Focus Area:
Transformation of Municipal and Rural Cooperative Electric Grids to Renewable Energy Microgrids



Developing Municipal Utilities Distributed Energy Microgrid

Aligns six independent electric utilities along regional transportation corridors to enable efficient manufacturing, transportation, communications

- **Quakertown**
- **Perkasie**
- **Hatfield**
- **Lansdale**
- **Philadelphia**
- **Navy Yard**



Have ample natural gas supply

CHP – Based Microgrid Investigated by Mid-Atlantic CHP as Key Enabler

Unregulated Micro-grid in Utility Constrained Area
Electric Growth Power Demand Projected: 25 MW → 80-100 MW

The Navy Yard at Philadelphia

28 MW peak power demand
(~ 6,000 employees)

Need 80 – 100 MW peak power available to achieve at total commercial Buildout (20,000 employees)

Have ample natural gas supply and multiple gas line access points

CHP Systems Insertion into Microgrid Investigated by Mid-Atlantic CHP as Feasible Solution

U.S. Department of Energy
CHP Technical Assistance Partnerships
MID-ATLANTIC

PENNSTATE

Procter & Gamble's Mehoopany Plant:
The "Triple Threat" of Natural Gas

- Proctor& Gamble's largest manufacturing facility in the world
- CHP an effort to save money and reduce CO2 emissions
- 64 MW of electricity
- Gross savings of $16.5millionperyear

P&G MEHOOPANY — BY THE NUMBERS

50,000,000+	Total investment in energy self-sufficiency (dollars)
200,000+	Construction hours created by Cogen2 installation, CNG station construction
875,000	Electricity from cogen units (megawatt hours/year)
480	Electricity sold to grid (megawatt hours/day, typical day)
20,000	Homes served by electricity sold to grid (typical day)
75	CNG over-the-road trucks purchased by commercial carriers to serve P&G
1,000,000+	Diesel fuel replaced by CNG (gallons, per year)
100,000+	CO2 emissions eliminated by Cogen2 (tons, per year)

Standby/Capacity Reservation Charge Best Practices and Review:

Prepared for Pennsylvania Public Utility Commission
CHP Working Group

April 16, 2019

By:

EXERGY Partners Corp.

entropy research, llc

8 MW GT with high 24/7 load factors
- Schedule 10 day maintenance outage
- 1 day unscheduled outage in July

1 MW Recip with intermediate load factor, 2 shifts @ 5 days/week
- Scheduled 36 hour maintenance outage
- 2 – 18 hour unscheduled outage – Feb, Jul

200 kw MT with typical office building schedule
- 12 hrs/day @ 5 days/week
- 15 day scheduled outage
- 1-12 hour unscheduled outage - July

We greatly appreciate the assistance of the following individuals in preparing and/or reviewing this report:

- Joseph M. Sherrick Supervisor Technical Utility Services, Policy & Planning, Pennsylvania Public Utility Commission
- Dr. James Freihaut, Director of DOE's Mid-Atlantic CHP Technology Assistance Partnership
- Vestal Tutterow, Laurence Berkley National Laboratory

We also acknowledge the rate review guidance provided by PECO, Duquesne Light and PPL.

Purpose of this Analysis

Standby tariffs and rates can affect the economic feasibility of CHP projects. Customers who receive all of their electricity from the utility are known as "full requirements" customers. Their electricity is provided under rates that are primarily some mix of fixed customer charges - a recurring charge (monthly or daily) intended to cover the constant costs of metering, billing, and service drop facilities; energy charges - the charges for consumption of the electricity commodity applied on a per-kWh basis; and demand charges – charges based on the peak electricity demand (kW) during a given period and used to recover the capital costs of the capacity necessary to meet the customer's peak loads. Customers with onsite generation typically require a different set of services, which includes continuing electricity service for the portion of usage that is not provided by the onsite generator, as

standard tariff for certain special types of services. Common components of service for partial requirements customers can include:

(1) *Supplemental Service*. Supplemental service for customers whose on-site generation does not meet all of the customer's needs. In many cases, it is provided under the otherwise applicable full requirements tariff.
(2) *Back-up Service*. Back-up, or stand-by, serves a customer's load that would otherwise be served by DG, during unscheduled outages of the on-site generation.
(3) *Scheduled Maintenance Service*. Scheduled maintenance service is taken when the customer's generator is due to be out of service for routine maintenance and repairs.
(4) *A capacity reservation charge* to compensate the utility for the capacity that the utility must have available to serve a customer during an unscheduled outage of the customers own generation unit.

Standby/Capacity Reservation Charge Best Practices and Review:

Prepared for Pennsylvania Public Utility Commission
CHP Working Group

Findings

The analysis raises a series of question regarding standby rate complexity, transparency and equity.

1. There appears to be little consistency between the EDCs with respect to standby charges.
2. Standby / Reservations charges and structure vary considerably between the three EDCs.
3. Descriptors vary widely for services, which fosters confusion.
4. PECO's CRR standby rate had a negative impact on the three CHP cases reviewed.
5. Duquesne's Rider 16 standby rate had a positive impact on the three CHP cases reviewed.
6. Tariffs descriptions were sometimes not clear – providing example calculations would help (one EDC had one example calculation).
7. Structures can be complex and difficult to properly apply without utility input. One example of utility assistance is from Ameren Missouri Rates group which has developed excel tools which customers can use to input projected load profiles and generation assumptions to estimate the impact of standby rider on their bill. https://www.ameren.com/missouri/business/rates/electric-rates/riderssr
8. There was no distinction between maintenance backup power (which can often be scheduled offpeak) demand and unscheduled downtime.

General Recommendation for Standby and Reservation Charges[3]

Summary of Best Practices in Standby

Rate Design

Based on the experience of RAP and BAI in the area of standby rate design, explained in Chapter 1, the following are best practices for consideration in the development of standby rates:

Allocation of Utility Costs

- Generation, transmission, and distribution charges should be unbundled in order to provide transparency to customers and enable appropriate and cost-based standby rate design.
- Supplemental power charges should be based on charges in the applicable full requirements tariff.
- Generation reservation demand charges should be based on the utility's cost and the forced outage rate of customers' generators on the utility's system.

Judgments Based on Statistical Method

- Standby rate design should not assume that all forced outages of on-site generators occur simultaneously, or at the time of the utility system peak.
- Transmission and higher-voltage distribution demand charges should be designed in a manner that recognizes load diversity.
- Standby rate design should assume that maintenance outages of on-site generators would be coordinated with the utility and scheduled during periods when system generation requirements are low.

Value of Customer Choice and Incentives

- Daily maintenance demand charges should be discounted relative to daily backup demand charges to recognize the scheduling of maintenance service during periods when the utility generation requirements are low.
- Customers should have the option to purchase all or some portion of their standby service on an interruptible basis and thereby avoid generation reservation demand charges.
- Pro-rated, daily, as-used demand charges for backup power and shared transmission and distribution facilities should be used to provide an incentive for generator reliability.
- Customers should be able to procure standby service from competitive power providers at prevailing market prices, where available.